Demand Response Recommendations and Implementation Status

In October 2015, the Roadmap for Implementing Michigan's New Energy Policy Steering Committee charged stakeholders with developing a vision and recommendations to promote demand response (DR) programs in Michigan. In response to this charge, stakeholders crafted their vision and recommendations (available on the project website) for demand response. Below is a summary of the stakeholder group's recommendation and implementation activities to date (as of March 2017).

Studying DR Potential

Recommendations	Implementation Status
Stakeholders noted that there has not been a comprehensive potential study of DR for several years and that a baseline study could be useful for energy providers and the state. Participants also noted that a potential statewide study would need to account for differences among utilities and across customer classes. The group generally agreed that a study for DR programs in Michigan could be an important aspect of completing an integrated resource plan (IRP) should such a plan be required by pending energy legislation.	Public Act 341 of 2016, section 6(t), requires regulated electric utilities to file an IRP. A requirement in the same section of PA 341 directs the commission to conduct an assessment for the use of demand response programs in the state. The results of the statewide DR assessment will then be used to establish IRP modelling scenarios and assumptions for use by the utilities in their required filings.

Structuring Customer Compensation and Ensuring Adequate DR Performance

The stakeholder group made the following recommendations for designing the three most common types of demand response rates.

TIME-OF-USE PRICING (TOU): Typically applies to usage over broad blocks of hours (e.g., on peak=six hours for summer weekday afternoon; off peak=all other hours in the summer months) where the price for each period is predetermined and constant.

Parameter	Recommendations	Implementation Status
Pricing/interruption period (frequency and timing)	Stakeholders believe that there could be two approaches for designing residential TOU rates—a simple and a complex approach. Stakeholders described that a two-tier TOU rate may prove to be simpler for customers to understand and potentially increase customer participation. This approach would employ a single, longer peak period from 2 PM–7 PM. Stakeholders also saw value in the three-tier TOU rate because this structure better reflects the cost of providing service, provides for stronger price differential signals, and may make it easier for participants to avoid energy use during shorter on-peak periods. Any program design should be specific to a utility's load profile and seasonal weather patterns.	**Implemented.** The state's two largest electric utilities DTE Energy and Consumers Energy have instituted two-tier and three-tier TOU rates. These rates were designed in accordance with stakeholders' recommendations. Per stakeholders' recommendation, the two-tier rate includes one long on-peak period and the three-tier rates have higher price differentials. The utilities' three-tier rates are no longer labeled experimental, and there are no limits on the number of participants. The Michigan Public Service Commission (MPSC) approved these rates in the utilities' most recent general rate cases (Cases U-17990 and U-18014).
Opt-in/out provision	During early stages, participation in TOU rates should be based on opt-in enrollment. Stakeholders commented that utilities should, where possible, provide standard-service customers with a comparison of what their bill would have been had they participated in a TOU rate. As programs mature and savings are demonstrated, stakeholders expressed that an opt-out approach could feasibly replace the opt-in provision. There was also the suggestion from some participants that, when applicable, utilities should automatically enroll customers in the rate class that best suits a customer's consumption habits based on 12 months of energy use data.	**Implemented.** The commission-approved TOU rates are opt-in only. In recent rate case orders, the commission rejected utilities' proposals to use three-tier rates as the default for new customers, commenting that "[the rate] is too complex to be set as the default rate for new residential and secondary commercial customers" (Case U-18014).
Notification method and timing	TOU rates make clear the different price levels associated with energy use at various times of the day. Notification is not necessary in TOU rates.	**Implemented.** Current two-tier TOU rates do not require customer notification.

On-/off-peak price ratio	Stakeholders noted that the on-/off-peak price ratio for utility TOU rates should—similarly to peak periods—reflect the nature of a utility's load profile and seasonal weather patterns. Stakeholders generally agreed that a range of on-/off-peak price ratios between three and 4.5 would be a good place to set initial rates. As utilities' experience with TOU rates matures, these price ratios should reflect experiences with customer participation and actual savings in avoided energy and capacity costs.	**Partially implemented.** The commission's recent orders established the following price differentials for TOU rates: ❖ DTE's two- and three-tier TOU rates feature on-/off-peak price ratios of approximately three. ❖ Consumers' TOU rates' price differentials are slightly lower, with 1.5 for their two-tier and 1.8 for their three-tier rates.
Incentive offered	Incentives should reflect the amount that produces the desired level of participation in and savings from these rates. Stakeholders commented that the appropriate level of incentives could be learned through utility experience over time. In TOU rates, the incentive should reflect the value of the avoided cost of energy consumption during peak periods and avoided costs of capacity otherwise needed to meet peak demands.	**In progress.** As utilities gain more experience with and customer feedback on their new TOU rates, they will be able to better optimize incentives to produce desired results.
Contract term	The typical length of time for customers to participate in a time-varying rate programs is one year. However, utilities should be allowed some flexibility with their individual programs in order to align with regional transmission operator (RTO) requirements and customer preferences. A customer's individual commitment should not imply that utilities' time-varying rate programs are unavailable after a customers' individual commitment. This point is important for customers whose participation in time-varying rate programs brings them to make investments in communicating devices or smart appliances.	**Implemented.** Stakeholders' recommendation was codified into Michigan law by Public Act 342 of 2016 Sec 95 (1) (a), which states "To participate in a [load management] program, a customer shall agree to remain in the program for at least one year."

CRITICAL-PEAK PRICING AND CRITICAL-PEAK REBATES (CPP and CPR): When utilities observe or anticipate high wholesale market prices or power system emergency conditions, they may call critical events during a specified time, and the price for electricity during these time periods is substantially raised. Two variants of this type of rate design exist: one in which the time and duration of the price increase are predetermined when events are called and another in which the time and duration of the price increase may vary based on the electric grid's need for reduced loads.

Parameter	Recommendations	Implementation Status
Notification method and timing	Residential customers should receive notification for a critical-peak event at least one day in advance. Stakeholders also noted that customers should be given the option to select the type of notification they receive (e.g., text, phone call, email). Customers should also be given the option to have a notification delivered directly to a communicating thermostat or smart appliance. This practice could encourage participation by removing an obstacle for customers.	**Implemented.** Current utility programs require notification to be given a day in advance of critical-peak events. DTE's approved tariff specifies that notification may be made via telephone, text message, email, or in-home device.
Critical-peak/off-peak price ratio	Stakeholders noted that the critical-/off-peak price ratio should—similarly to TOU peak periods—reflect the nature of a utility's load profile and seasonal weather patterns. As utilities' experience with critical-peak rates matures, these price ratios should reflect experiences with customer participation and actual savings. Utility participants noted that their peak pricing programs use critical-peak prices set at $0.95.	**In progress.** More experience with and expanded participation in TOU rates will enable utilities' to further optimize critical-/off-peak price differentials. Currently, Consumers and DTE continue to use critical-peak prices of $0.95.
Price vs. rebate	Utilities should provide access to both CPP and CPR programs, at least in pilot projects, until the best program results are determined. Stakeholders believe that participation would be higher in CPR programs but noted that these programs add an extra administrative and accounting step that could lead to higher program operating costs.	**In progress.** Only Consumers offers CPP and CPR programs. New and expanded program offerings are expected as utilities garner more experience in offering CPP and CPR programs.
Incentive offered	Incentives should reflect the amount that produces the desired level of participation in and savings from these rates in avoided energy and capacity costs associated with the customer response. Stakeholders commented that the appropriate level of incentives could be learned through utility experience over time.	**In progress.** Incentives offered will be further refined as utilities gain more experience in offering critical-peak rates and learn from customer participation and feedback.
Contract term	The typical length of time for customers to participate in critical-peak programs is one year. However, utilities should be allowed some flexibility with their individual programs in order to align with RTO requirements and customer preferences. A customer's individual commitment should not imply that utilities' critical-peak programs are unavailable after a customer's individual commitment. This point is important for customers whose participation in critical-peak programs brings them to make investments in communicating devices or smart appliances.	**Implemented.** Stakeholders' recommendation was codified into Michigan law by Public Act 342 of 2016 Sec 95 (1) (a), which states, "To participate in a [load management] program, a customer shall agree to remain in the program for at least one year."

DIRECT LOAD CONTROL (DLC) PROGRAMS: When utilities observe or anticipate high wholesale market prices or power system emergency conditions, they may call critical events during prespecified time periods, the price for electricity during these time periods remains the same but the customer is refunded at a single, predetermined value for any reduction in consumption relative to what the utility deemed the customer was expected to consume.		
Parameter	**Recommendations**	**Implementation Status**
Opt-in/out provision	Participation in DLC programs should be on an opt-in basis. Once enrolled in a DLC program, residential customers would not be able to opt out of any cycling events for the duration of their contract commitment. Stakeholders commented that allowing customers to opt out of a DLC event would place the utilities' capacity commitments with their RTO at risk. Stakeholders noted that if customers were able to opt out of an event, a penalty requisite with the potential penalty the utility would face for nonperformance from the RTO would be required. Some utilities currently offer the option for a customer to opt out of one event per year, as long as the utility is given sufficient notice. This provides a customer with some flexibility.	**Implemented.** Currently DLC programs require a customer to opt-in. Consumers' DLC program allows the customer to opt-out of one load control event per summer. Additional opt-outs granted by Consumers may result in the customer's bill credit being forfeited.
Notification method and timing	Notification for DLC or air conditioning (AC)-cycling programs should not be a requirement. However, customers should be able to determine whether they are being cycled through their utility account online, via an opt-in communication from their utility, or directly from their appliance. This would ensure customers can determine whether they are experiencing mechanical difficulties with their appliance or if their experience is the result of DLC.	**Implemented.** Stakeholders' recommendation is reflected in Consumers and DTE's DLC programs.
Pricing/interruption period (frequency and timing)	DLC programs may vary depending on what appliances are being controlled. Michigan has years of successful utility AC-cycling programs on which to model new programs. AC-cycling programs should run from June through September and cover up to eight hours each day at a cycling rate of 15–30 minutes out of every hour.	**Implemented.** Stakeholders' recommendation is reflected in Consumers and DTE's DLC programs.
Price vs. rebate	Residential customers participating in DLC programs should receive a payment for their participation. Payments could potentially be in the form of a monthly bill credit, but utilities should have the flexibility to design payments so that they align with customer interest.	**Implemented.** DTE offers customers a discounted rate for their participation in DLC programs. Consumers offers a monthly bill credit.
Incentive offered	The level of incentive offered to participating DLC program customers should be correlated with the cost savings such programs produce. The amount of incentive should also be set at a level that is enough to drive customer participation in DLC programs. This determination would be made based on utility experience.	**In progress.** With more experience and participants on DLC rates, utilities will further optimize incentives. The monthly bill credit offered by Consumers is based on the summer incremental capacity costs as outlined in their general rate case.
Contract term	The typical length of time for customers to participate in a DLC programs is one year. However, utilities should be allowed some flexibility with their individual programs in order to align with RTO requirements and customer preferences. If participating in a DLC program requires a customer to make an investment in a communicating device or smart appliance, then a customer should have assurance that the program will be in place for longer than their individual commitment and that they will be given the opportunity to continue participation as they choose.	**Implemented.** Stakeholders' recommendation was codified into Michigan law by Public Act 342 of 2016 Sec 95 (1) (a), which states, "To participate in a [load management] program, a customer shall agree to remain in the program for at least one year."

Structuring Utility Compensation and Measuring Performance

The stakeholder group made the following recommendations for compensating utilities for delivering DR programs and measuring program performance.

Recommendation Category	Recommendations	Implementation Status
Measuring program performance	To measure progress toward achieving the stakeholder group's vision for DR programs in Michigan, the level and type of customer participation in cost-effective programs should be tracked. To that end, the stakeholder group recommends using the percentage of load per customer class participating in DR programs, as well as the net system savings through the use of DR (dollars per megawatt [$/MW]) cost of DR relative to the $/MW cost of traditional investment) as the types of metric to be used to evaluate whether or not the DR vision is being achieved. These metrics should be specific for utilities and customer classes (as opposed to establishing a single, statewide target metric). Utilities are already collecting the necessary data to be able to evaluate progress toward these metrics, so the group thought these were not only the most important metrics, but also the most feasible to track. Utility-proposed targets should be grounded in the understood, cost-effective potential, as well as the anticipated need as determined by an IRP.	**Implemented.** The MPSC's orders in cases U-17936 and U-18013 require DTE and Consumers to file monthly and annual reports containing the data necessary to determine program performance on recommended metrics. These metrics are specific to individual utilities and differentiated by customer class and program. Targets or goals for these metrics will be developed as part of the utilities' separate IRPs. Modelling scenarios for utilities' IRPs, including the use of DR, are currently being drafted through a statewide stakeholder process.
Utility compensation	Utility compensation for delivering DR programs should be based on a combination of cost recovery and an opportunity to earn a performance-based return as follows: ❖ Full cost recovery of prudent program expenditures: The costs of implementing DR programs can include capital (communication infrastructure, load control devices) and noncapital (marketing, administration, incentives) expenditures. Recovery of these costs could occur as an expense—for example, through a reconcilable surcharge—or through rate base. If cost recovery is done through rate base, both capital and noncapital DR program expenditures should be included, and utilities should be allowed the opportunity to earn a rate of return on their program investments. ❖ Performance reward: Utilities that operate DR programs effectively and generate net system savings should be eligible for a performance incentive. The incentive should be tied to achievement of agreed-upon performance metrics (e.g., participation, threshold peak demand reduction, program cost effectiveness, or minimum net system savings). The performance incentive could be structured as a percentage of program spending, as a share of net system savings, or as a premium rate of return on their program investment. Utilities should be awarded performance incentives only if they meet or exceed threshold performance levels and the incentives should not exceed the net system savings generated through the DR programs. A portion of net system savings should be used to lower system costs/rates for all customers. In addition to these benefits, participating customers should also be eligible to receive incentives.	**Cost Recovery: Implemented.** Stakeholders' recommendation was codified into Michigan law by Public Act 342 of 2016 Sec 95 (3) which states, "The commission may allow a provider whose rates are regulated by the commission to recover costs for load management through base rates as part of a proceeding under section 6a of 1939 PA 3, MCL 460.6a, if the costs are reasonable and prudent and meet the utility systems resource cost test." **Performance Reward: In progress.** Stakeholders' recommendation was codified into Michigan law by Public Acts 341 and 342 of 2016 which include the financial incentive mechanism which could be extended to DR program spending. PA 341 also includes a provision allowing the use of a shared savings mechanism in utilities' IRPs. Utilities may also propose alternative performance reward mechanisms in cases before the commission. A stakeholder group will be discussing the framework for evaluating and rewarding demand response programs throughout 2017.
Measuring program cost effectiveness	The stakeholder group recommended using either the utility-cost test or total-resource-cost test, or a combination of the two, to measure program cost effectiveness. The utilities already use this methodology, so it is both appropriate and feasible. This method compares the $/MW for the utility to implement a DR program to the $/MW saved by avoiding capacity generation. The group thought it was important that the costs and benefits be delineated by time (season and time of day) and location (local and regional effects) and normalized for variations in weather and regional economic conditions.	**Implemented.** Stakeholders' recommendation was codified into Michigan law by Public Act 342 Sec 95 (3) which states, "The commission may allow a provider whose rates are regulated by the commission to recover costs for load management through base rates as part of a proceeding under section 6a of 1939 PA 3, MCL 460.6a, if the costs are reasonable and prudent and meet the utility systems resource cost test."
Program reporting	The stakeholder group thought both prospective and retrospective reporting should be done. Utilities may submit a prospective DR plan to the MPSC—or include it in the integrated resource planning process, if appropriate—to ensure program costs are just and reasonable. Costs of a prospective plan preapproved by the MPSC should be deemed eligible for recovery. This can be done as part of a utility's regular rate proceedings or separately. If an RTO has already determined a utility's DR program is an eligible capacity resource, then there is an accelerated review and approval process.	**Implemented.** The MPSC's orders in cases U-17936 and U-18013 require DTE and Consumers to file monthly and annual demand response reports. These reports must include detailed accounts of participation in DR programs, available MW of demand reduction, resource capacity reported to the RTO, energy savings, and program spending. The data provided in these reports will allow

	The utilities should then be required to annually submit a retrospective performance report on what was accomplished so that the reward can be approved. The group stressed the importance of transparency, so these reports should be shared by the MPSC publicly. However, individual customers should be treated as private.	stakeholders to develop performance measures to evaluate the effectiveness of utility DR programs. Forward-looking DR plans will be featured in utility IRPs.
Integrating DR with energy-efficiency plans	MPSC should be willing to consider integrated plans that include DR, energy efficiency, and other measures.	**In progress**. Demand response is included, to some extent, in the portions of PA 342 related to energy waste reduction (EWR) plans. MPSC will be hosting a stakeholder group to discuss the framework for evaluating and rewarding demand response programs throughout 2017, including integration with EWR.
Third-party verification	Findings from the retrospective performance reports should be verified annually by a third party hired by the utility. Identification of third-party verification contractor, or the process and qualifications for securing the third-party verifier, should be included in the prospective DR plan noted in a preceding bullet. Both the utilities proposing DR programs as well as DR providers should be monitored to ensure they are delivering intended results.	**Not implemented.**
RTO verification	An RTO's approval of DR programs used by a utility to meet its resource adequacy requirement should be sufficient to meet the requirement for third-party verification.	**Not implemented.**